

# MARKET MONITORING ORGANIZATIONS IN ELECTRICITY: WHAT CAN WE LEARN FROM THE ECONOMICS OF REGULATION?

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## I. Introduction

### A. Market Monitoring

Electricity restructuring has produced market institutions quite unlike those of any other deregulation. Independent system operators (ISO) have replaced insular utilities to control transmission in several regions, and the Federal Energy Regulatory Commission (FERC) has virtually mandated their formation in all other regions.<sup>1</sup> By controlling the systems of several utilities at once the ISO allows nondiscriminatory scheduling of power transactions and reduces the cost of arranging and paying for power flows over interconnected systems. Exchange institutions (PXs) for trading short-term (delivery one day or less ahead) power and reserves are also in place. Most of the power that an ISO schedules, however, is either generated by vertically integrated utilities for their own final (“retail”) customers or flows under longer-term bilateral contracts. Through an ongoing set of policy developments the FERC has authorized market-based (as opposed to regulated) rates for sales by utilities and non-utility generators if their local ISO has Commission-approved market monitoring institutions (MMI) in place.

The ISO, PX, and MMI are all fundamentally novel developments. The physics of electricity flows and the institutions of ratemaking necessitate the use of ISOs to efficiently schedule the growing volumes of market-determined power flows. A centralized power exchange can determine market-clearing prices for both short-term energy and the transmission services needed to move it. Some allocational decisions might be more efficiently made by a market than by the orders of a centralized system controller. The rationale for a market monitor is less clear. The Federal Power Act and subsequent legislation require that FERC set “just and reasonable” rates, but these may be market-determined if the Commission finds sufficient

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<sup>1</sup> Order No. 2000, Regional Transmission Organizations, F.E.R.C. Stats. & Regs. ¶ 31,089 (2000), 65 Fed. Reg. 809 (2000) (codified at 18 C.F.R. pt. 35) [“Order 2000”].

competition.<sup>2</sup> Parties claiming competitive harm in transactions administered by an ISO or PX can still petition FERC for redress, and the antitrust courts sometimes offer yet another alternative. The additional value of an MMI remains to be determined. One possibility is that no existing institution will have local specialists who can identify problems and possibly remedy disputes that will unavoidably arise in a complex new system of markets. An MMI might thus efficiently replace a lengthy regulatory process, particularly if the institutions are ones that regulators have little experience and no obvious advantage in supervising.<sup>3</sup>

Relationships between the MMI and the ISO or PX may take alternative forms. Some MMIs are staffed by employees of those institutions, as occurs in the New York and California ISOs and was the case for the now-bankrupt California PX. The staff of an MMI can also be appointed and operate at arm's length from the market organization. Alongside their in-house monitoring staffs, California's ISO and PX each also have (had) external monitoring panels staffed by distinguished academics and lawyers. Those panels can evaluate the work undertaken by internal monitors and can institute their own investigations without interference from the organization's administrators. In some other ISOs the external monitoring function is governed by a contract with a consultant who has access to necessary data. One firm, Potomac Economics, provides monitoring for the New York ISO, ISO-New England, the Midwest ISO, and the Electricity Reliability Council of Texas. All monitors must provide FERC with regular (annual or more frequent) reports on the markets they oversee.

There are no clear analogues of the MMI in other regulated industries. After full deregulation of the wellhead price of natural gas, antitrust is the only recourse for those alleging monopolistic conduct.<sup>4</sup> The partial deregulation of pipeline rates has brought decentralized markets for capacity exchange among users, with FERC's remaining role the enforcement of cost-based ceilings. No organization monitors capacity exchanges, and in practice FERC allows circumvention of its ceilings by "buy/sell" transactions that bundle gas and pipeline capacity in a single-price package.

Supporters of MMIs in electricity have analogized them to the institutions that oversee individual securities and commodities exchanges that are under the ultimate authority of the SEC and CFTC. The monitors of these "self-regulating organizations" are in practice committees of interested users of the market, or groups such as the National Association of Securities Dealers.

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<sup>2</sup> Federal Power Act 205, 16 U.S.C. 824d(a) (1994).

<sup>3</sup> Lock (1998), Barker et al (1997) at 301.

<sup>4</sup> One helpful way to view the treatment of electricity is that the antitrust laws are triggered by actions of market participants, while FERC's nearly unique "just and reasonable" standard can be viewed as requiring continuous oversight of market performance. It is still possible, however, that FERC may move to an act-based standard if markets are sufficiently competitive. See Fox-Penner *et al* (2002) at 297.

They have powers to arbitrate disputes, suspend traders, propose new contracts, and set such rules as maximum price movements over a day. Unlike these institutions, MMIs are products of regulation rather than requirements of federal law. Regulatory organizations for stock markets only have the power to levy penalties after formally structured hearings in which the accused are afforded normal legal protections, while the powers of MMIs are still largely uncertain and context-dependent. (Raskin 1998) Perhaps the largest difference is that market participants themselves are the membership of self-regulatory exchange monitoring groups. (Doherty *et al* 1991)

MMIs in electricity are to be staffed by individuals with no market interests. FERC has envisioned their primary role as that of an information conduit to the Commission, which will subsequently investigate and make policy. Greater autonomy for MMIs is also a possibility. The New York ISO's monitor can order automated remedies (built into the system's computerized dispatch) if it sees certain well-defined conditions. The Pennsylvania-New Jersey-Maryland Interconnection's (PJM) monitor has the power to demand that a market participant cease violating the organization's rules, but PJM's has also stated that its MMI does not have enforcement powers.<sup>5</sup> A lack of due process in most MMIs has been cause for concern (Raskin 1998) but appears to have produced few problems in practice.

## B. Emerging MMI Policies

FERC intends that MMIs play a more important role than currently as RTOs are formed and market designs are standardized. If nothing else, the Commission appears to expect that MMIs by themselves will largely suffice to discourage potentially successful withholding behavior by entities with high market shares of generation capacity. Its revised standard for market-based rates will deny them to a utility whose share of generation in its service territory is great enough that operating some of it is necessary to meet the area's peak load. Most utilities own substantial capacity near their loads and will fail such a test. FERC will nevertheless grant MBR authority to such a utility if it has joined an RTO that has a Commission-approved MMI in place, apparently regardless of any other indicia of market power that the utility might possess.<sup>6</sup> FERC took numerous comments on MMIs in the process of formulating Order 2000, but that Order fails to specify the necessary characteristics of MMIs, the standards they must use, or the powers that the MMI will have. For an institution deemed a *sine qua non* for competition, the Commission has been remarkably vague:

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<sup>5</sup> See references in Fox-Penner *et al*, *supra* note 4 at 338.

<sup>6</sup> Order on Triennial Market Power Updates and Announcing New, Interim Generation Market Power Screen and Mitigation Policy, 97 FERC ¶ 61,219 (2001). FERC clearly wants its jurisdictional utilities to join RTOs but is apparently taking this path because it is unsure of its powers to order membership under the Federal Power Act.

...In light of the different forms of RTOs that could be developed by market participants and the varying types of markets an RTO may be operating within its region, different market monitoring plans are likely to be appropriate for different RTOs. Consequently, after careful consideration of the comments, the Commission will require that RTO proposals contain a market monitoring plan that identifies what the RTO participants believe are the appropriate monitoring activities the RTO, or an independent monitor, if appropriate, will perform.

...Although we decline at this time to prescribe a particular market monitoring plan or the specific elements of such a plan, the RTO must propose a monitoring plan that contains certain standards. The monitoring plan must be designed to ensure that there is objective information about the markets that the RTO operates or administers and a vehicle to propose appropriate action regarding any opportunities for efficiency improvement, market design flaws, or market power identified by that information.

...The monitoring plan should indicate whether the RTO will only identify problems and/or abuses or whether it also will propose solutions to such problems.<sup>7</sup>

Quoting these passages, Fox-Penner *et al* noted that “[i]n terms of the economic standards of workable competition or the process to judge it, these requirements are nearly content-free.”<sup>8</sup>

It thus appears that the activities of MMIs will be major influences on the development of power markets, but that the shapes that MMIs take and the policies they make will be determined as much by politics as by economics. The vagueness of Order 2000 virtually ensures that their details will evolve haphazardly by compromises and idiosyncratic responses to local conditions over the next several years. FERC appears to be setting the policies toward these critical institutions in a vacuum that disregards both economics and the available history of MMIs.

Of equal interest is the path MMIs took to policy prominence. California’s were introduced with no debate about their appropriateness relative to other institutions for dealing with the perceived problems they were expected to alleviate. ISOs that were formed later appear to have introduced MMIs with equally little thought about their conceptual bases and little concern about the efficacy of introducing them into a market environment. As existing ISOs came to have MMIs, FERC also declined to evaluate possible alternatives, or even to examine the performance of MMIs already in place. An accident of California politics has metamorphosed through naivete and neglect into a national policy of mandatory MMIs. These ill-specified institutions with little accountability will be critically important for the future of electrical competition. For FERC the hour may be late, but it needs to draw what inferences it can from the histories and functioning of already-existing MMIs.

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<sup>7</sup> Order 2000 at 31,155-6.

<sup>8</sup> Fox-Penner *et al*, *supra* note 4 at 337.

Economists in particular seem to be viewing MMIs with unwarranted optimism. In analyzing so critical an element in this most complex and politicized of all deregulations, they have seldom thought to review the voluminous research on intervention that they themselves have produced. This paper examines MMIs in light of that work. The history of California's and other MMIs provides a record, already almost forgotten, that is quite consistent with the economic theory of regulation. MMIs were first proposed by parties with direct interests in the policies they would produce, rather than by disinterested experts or a consensus of representative interests. An important part of their subsequent behavior is more consistent with their political origins than with a belief that they were simply called into being to discharge a broader public interest.

The next section provides a summary of the economics of regulation, including some empirical findings of relevance to the question of how MMIs might function in overseeing markets that are both economic and political in nature. Section III then provides more details on the events that shaped California's institutions and examines their consistency with the that economics. Section IV presents a comparison of the behavior of the four existing ISOs (the ones that operate PXs) and their MMIs in coping with "virtual bidding" by market participants. To allow virtual bidding is to allow arbitrage transactions between day-ahead and real-time electricity markets. Supply or demand is bid into them and bought or sold back in real-time. The various ISOs treated this unquestionably efficient practice in ways that track their underlying economics and politics with surprising accuracy. PJM instituted virtual bidding without controversy on the same day that its markets opened for business. New York had a different constellation of interests that succeeded in postponing its introduction for over two years. New England had a substitute method available to its market participants and little controversy ever surfaced. At the other extreme, California in effect made the practice illegal.

## **II. The Economics of Regulation and Regulatory Politics**

### **A. Economists and Regulators**

Economists have long been schizophrenic on regulatory matters. A tradition going back to Adam Smith has modeled markets, set criteria for efficiency, observed reality, and unsurprisingly concluded that reality falls short of theoretical perfection. (Stigler 1965) As government's role in the economy expanded, economists observed that it seldom if ever put in place the regulatory institutions that theory had shown to be efficient. Those giving policy advice usually found little interest in efficiency on the part of elected officials, and considerably more interest in creating inefficient institutions. Two centuries after Smith, a second set of economists

began to ask if economics itself could shed light on the politics of regulation. (Stigler 1971, Peltzman 1976, Becker 1983) If politicians purchased support from various interests, they might repay those interests by restricting competition and transferring wealth in ways that were superficially inefficient.

The once-dominant “public interest” model of regulation literature had straightforward applications to electricity: marginal cost (including Ramsey) pricing, peak-load pricing, efficient resource choices, and the determination of allowed rates of return for utilities are all major contributions to knowledge. Prior to Alfred Kahn’s ascendancy, they were at best minor contributions to policy. Regulators now had the relevant theory, but they often continued to set rates and service policies in ways that economists found unsatisfactory. Acknowledging the inherent ambiguity of the “public interest” in passing, economists still had little difficulty in simply assuming that it usually took the form of efficiency and was best fostered by competition. As competition became feasible in industries that were once natural monopolies, regulators again failed to satisfy economists, opening markets more slowly and incompletely than the economists believed was warranted.<sup>9</sup>

## B. Electricity regulation and politics

Prior to the 1960s, economists had never studied the actual effects of regulation, an odd omission given the mass of public data that regulators collect. Stigler and Friedland’s pioneering 1962 study found that state electricity regulation had virtually no effect on prices after one accounted for their other determinants.<sup>10</sup> This finding, however, left researchers to identify the political or economic forces that had made nominally powerful regulatory institutions appear ineffectual. Historians pointed out an extensive record of utilities seeking state regulation, either as protection from franchise-related extortion by local governments or as a method to protect their profits from potential competitors.<sup>11</sup> Jarrell (1978) attempted to determine the interests that led to the introduction of state regulation between 1900 and 1930. Using multiple regression he was able to reject a public interest (consumer interest) theory by showing that regulation came earlier to those states where utilities earned low rates of profit, as opposed to states in which in

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<sup>9</sup> Economists themselves had little difficulty in devising coherent models that found limitations on competitive entry or barriers to it that might be efficient. They included multiproduct monopoly, efficient component pricing, empty cores, and implicit long-term contracts.

<sup>10</sup> Stigler and Friedman compared average power prices in the early 20<sup>th</sup> century between states that had and had not yet introduced public utility commissions.

<sup>11</sup> See Jarrell (1978 at 269-275) and Knittel (1999 at 13-16) and references therein for an introduction to the issues.

which consumers suffered under high prices.<sup>12</sup> Knittel's (1999) estimation of a statistical variant of Jarrell's model found less evidence for a producer protection hypothesis, but also no evidence for a consumer interest explanation. Economists have also examined the rate structures that will arise under regulation. Those of electric utilities appear to cross-subsidize different classes of customers in accordance with a theory that has them maximizing political support, as opposed to one in which they impartially set efficient Ramsey prices. (Primeaux and Nelson 1980, Nelson 1982)

Others have found that the institutional details of regulation influence its outcomes. Using a large sample of rate reviews initiated by utilities during the 1980s, Holburn and Spiller (2002) attempted to estimate the differential effects in states with officially designated utility consumer advocates, and in states with elected rather than appointed regulators. They found that the presence of a consumer advocate lowered the yearly probability that utilities in a state would initiate rate reviews by 4.5 percentage points, and that elected commissioners lowered it by 11.6 percentage points. The presence of consumer advocates lowered allowed returns on equity by between 0.19 and 0.37 percentage points, and that of elected commissioners lowered it by between 0.56 and 2.1 percentage points. Regulators in states with Republican-controlled legislatures granted higher allowed ROE than average, while those controlled by Democrats granted lower ROE. Variables measuring the strength of consumer and industrial interests also had some power in explaining rate structures.

Economists have also examined the determinants of electricity restructuring, attempting to predict or explain which states would initiate proceedings to bring competition for retail customers. (They have not yet attempted to explain which states would be the first to lose interest in restructuring.) Measures of the political strengths of incumbent utilities and large customers are important determinants of the decision, as are rates that substantially exceed the national average.<sup>13</sup> (White 1996, Ando and Palmer 1998). FERC itself has recognized the potential for politicized decisions by ISO governing boards that apportion seats to political interests. This has been a major factor reason for its continuing battle with California government over the independence of the state's Electricity Oversight Board and the Directors of its ISO.<sup>14</sup> New York's has been such a product of politics (see text below) that governors representing different interests have percentage vote shares that contain two decimal points. The composition

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<sup>12</sup> Jarrell (1978). By contrast, Emmons (1997) found that power prices in the 1930s were lower for customers of regulated and publicly owned utilities than was the case in still-unregulated states.

<sup>13</sup> See White (1996) and Ando and Palmer (1998). Oddly, in California the first documentary consideration of direct retail access was produced by the Strategic Planning Division of the state's Public Utilities Commission. (CPUC 1993)

<sup>14</sup> The conflict, which continues to the present began with a December 2000 FERC order to reconstitute the ISO's governance. See San Diego Gas & Electric Co., *et al*, Order Directing Remedies for California Wholesale Electric Markets, 93 FERC ¶ 61,294 (Dec. 15, 2000)

of “stakeholder” boards that govern non-profit ISOs by voting may in fact render them particularly vulnerable to both inconsistent decisions and deadlocks. (Michaels 1999)

### C. Regulatory Politics Beyond Electricity

Studies of interest groups and the effects of regulation now cover virtually every relevant industry. (Peltzman 1989) The types and ranges of effects vary widely. Regulation has at times protected the profits of incumbent producers, as was the case in railroads under the now defunct Interstate Commerce Commission. The coming of intercity trucking so threatened this redistribution that truckers were also put under regulation. State regulatory restrictions on branch banking in the name of preserving competition in effect subsidize inefficiently small banks. At other times they appear to benefit small consumers.

The presumption that antitrust agencies act to enforce a non-political public interest is also in doubt. No one has yet found a consistent relationship between the bringing of suits and the efficiency gain from successful prosecution.<sup>15</sup> Price-fixing cases brought by the government seem to center on ineffective collusions (Marvel *et al* 1988) and are directed at firms with low profitability. (Asch and Seneca 1976). Using internal FTC data, Coate *et al* (1990) were able to show that the concentration and entry criteria of the federal Merger Guidelines were important determinants of challenged mergers. Nevertheless the degree of political pressure on the Commission (as measured by Congressional actions) significantly increased the explanatory power of their regression equations.

One thing is clear: only in exceptional circumstances will regulation work according to the prescriptions of a public interest model.<sup>16</sup> There is as yet no theory or empirics that attempts to identify those exact circumstances. The introduction of a regulatory institution is a political decision that will reflect the identities and relative strengths of the affected interests. The next section examines the origin and performance of market monitoring in this context. The outcomes of a regulatory institution should also reflect these interests. Section IV illustrates this by examining the variant treatments of “virtual bidding” by various ISOs and their MMIs.

## **III. Market Monitors**

### A. The Origin of California’s MMIs

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<sup>15</sup> See references in Coate, Higgins, and McChesney (1990) at 465-46.

<sup>16</sup> FERC’s restructuring of the gas industry during the 1980s and 1990s appears to have been one of the few clearly efficient regulatory episodes in recent history. See Michaels (1993).

In 1994 the California Public Utilities Commission (CPUC) initiated a rulemaking on direct access by retail customers of the state's corporate electric utilities to suppliers of their choice.<sup>17</sup> The radical proposal followed on two decades of centralized planning and retrospectively poor investment decisions that had saddled the state with some of the highest rates in the nation. The state's utilities had two prime concerns: to maintain as much of their customer base as possible, and to recover the costs of above-market power contracts and generation investments ("stranded costs") that would probably become uneconomic after competition arose. Two years of hearings and negotiations followed, much of them devoted to a conflict between two visions. On one side was a bilateral contract model of direct transactions between customers and non-utility suppliers. On the other was a wholesale pool model in which utilities with continuing retail monopolies would pass through energy rates that had been set in a statewide bid-based energy market where participation would be mandatory. The bilateral model was favored by most independent power producers and marketers, large consumers, and Pacific Gas & Electric, the utility serving most of Northern California. The pool model was favored by the other two large utilities, along with some but not all environmentalists and small consumer advocates.

California's basic restructuring statute, known as Assembly Bill (A.B.) 1890, passed both legislative houses unanimously and became law in October 1996. A.B. 1890 quieted the bilateral / pool controversy by allowing direct access to suppliers by bilateral contracts for all power users as well as an initiating an ISO and a PX. Utility retail customers received a legislated rate freeze (small ones got a bond-financed discount) over a transition period that would mostly end in March 2002. Unlike other suppliers, the three large utilities were required to purchase all of their requirements in markets operated by the PX and ISO, and to bid all of their generation into those markets. The utilities would ideally collect all of their transition costs in the residual between frozen rates and market-determined energy prices. AB 1890 also mandated the divestiture of approximately half of the utilities' in-state fossil generators, with any gains above book value to be applied to transition charges. Within two years the utilities had divested virtually all of that generation, while retaining their hydro, nuclear, and coal facilities.

The utilities thus had an interest in low prices at the PX and ISO that would maximize the likelihood of transition cost recovery in the allowed time, alongside an interest in retaining their retail loads as part of a longer-term competitive strategy. While A.B. 1890 mandated the existence of these institutions, it said virtually nothing about the details of their design. Since those institutions would handle wholesale transactions (defined as sales intended for resale to ultimate customers) they were almost entirely within FERC jurisdiction and could only operate with its approval. Because the PX and ISO would determine time-varying energy prices rather than set them by cost of service, the institutions would have to pass FERC's market power screen in order to sell at market prices.

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<sup>17</sup> CPUC, Order Instituting Rulemaking and Order Instituting Investigation, Docket Nos. R.94-04-031 and I.94-04-032 (April 20, 1994). All links to this document have been removed from the CPUC web site.

Well before A.B. 1890 became law in late 1996 the design of these institutions was already well along. In December 1995 the CPUC had ordered a mandatory PX, and interested parties led by the three large utilities began designing the institution, originally known as WEPEX (Western Power Exchange). The available record is sketchy, but it seems clear that the utilities dominated the design process.<sup>18</sup> They were the only members of the original WEPEX Steering Committee, which subsequently added “several [actually 11] advisory members representing a spectrum of stakeholder interests.” Six of them were from municipal utilities and two from state regulatory agencies. They “participated in Steering Committee meetings and expressed their views directly to the Applicants’ [utilities] Steering Committee members.”<sup>19</sup> While committee meetings were open to all interested parties, the three utilities were the only parties allowed to vote.<sup>20</sup> In addition to the Steering Committee, there were at least six other working groups who held frequent and separate meetings. The various participating utilities (including municipals) and regulatory agencies were the only entities with near-guaranteed recovery of all the costs incurred in committee participation and meeting attendance.

## B. FERC Filings and Decisions

In April 1996 the utilities filed at FERC for approval of a PX that would sell at market-based rates. During the summer months they filed their market power studies. Using FERC’s screen in separate hub-and-spoke analyses, the three utilities broadly concluded that when transmission constraints were not binding (90 percent of the time) the relevant market was the entire Western Systems Coordinating Council, covering the northwest, southwest, and California.<sup>21</sup> When transmission was constrained the market covered a smaller territory, at times small enough that the utilities would not pass the market power screen.

To meet the expected objections the utilities proposed an assortment of mitigation measures, including further divestitures of generation beyond the 50 percent required by A.B.

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<sup>18</sup> The California PX’s website vanished with its January 2001 bankruptcy, and a site containing WEPEX documents and meeting records has done likewise. The CPUC recently revamped its web site to restrict access to available full-text Commission rulings and testimonies to those filed after Jan. 1, 2000.

<sup>19</sup> Joint Application of [PG&E, SCE, and SDGE] for Authority to Sell Electric Energy at Market-Based Rates Using a Power Exchange, Docket No. ER96-1663-000 (April 29, 1996) at A-1 – A-5.

<sup>20</sup> See letter from CPUC President Daniel Fessler to the WEPEX Steering Committee, Jan. 31, 1996, quoted in Motion to Intervene of the California Municipal Utilities Association, Docket No. ER96-1663-000, at 3.

<sup>21</sup> Pacific Gas & Electric Company *et al*, Order Providing Guidance and Convening a Technical Conference (Dec. 18, 1996), 77 FERC ¶ 61,265, Slip Op. at 5. This statement is substantially in conflict with definitions restricting the relevant market to California for the analysis of prices during the 2000-2001 crisis and the calculation of refunds payable by generators.

1890, the introduction of “must-run” contracts with California generators that might otherwise be able to exercise market power, and performance-based ratemaking. In addition, SCE and SDGE proposed market monitoring, but at this early date (May 1996) they filled in few details other than to list some of the data that an MMI might collect.<sup>22</sup> Significantly, no intervenor of any kind suggested a market monitoring plan in its own filing.<sup>23</sup>

At a technical conference in September 1996 utility representatives made clear that the MMI should be acting like a regulatory agency. In particular it should collect data on generator marginal costs that it could compare with bids. Questions about the proper relationship of bids to startup and minimum load costs gave the first hints of a debate that would later play out in the still-ongoing refund proceedings. Utility and small consumer representatives explained why only generation-owning utilities should have the right to build new transmission.<sup>24</sup> Both utility and consumer representatives favored centering the power to determine violations and levy fines in the ISO itself rather than undertaking lengthy FERC proceedings, an odd posture for the entities that appeared at the time to be the most likely to exert market power. With prior filings and conferences as a basis, in December 1996 FERC ordered the ISO to file a detailed monitoring plan that included [1] who bears responsibility, [2] the data to be collected, [3] criteria for identifying exercise of market power, [4] mitigation actions to be taken if market power was identified, and [5] the reports that would be filed with the Commission. In addition, technical conferences were scheduled.<sup>25</sup>

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<sup>22</sup> See Supplement of Southern California Edison company and San Diego Gas & Electric Company to Application, Docket No. ER96-1663-000 (May 29, 1996), Chapter IV.

<sup>23</sup> Prior to the opening of the markets the opportunities for “gaming” them were fairly apparent, and it is hard to believe that they were unknown to the utilities that had presided over their design. It is now known that a group of individuals from Perot Systems both played a role in the formulation of the PX protocols and that they had prepared presentations that the PX originally intended to use to inform potential traders about methods of exploiting then-known loopholes in the protocols. It is also known that at least one of the major utilities was in contact with members of the same group, who had informed them about these conditions that ultimately made up part of the operating rules. In some cases, a buyer would be able to lower prices by engaging in obverses of the transactions that sellers could use to raise them. See Statement of George Backus, President, Policy Assessment Corporation, before the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs, Committee on House Government Reform, July 22, 2002; also “Perot E-Mails Said to Show Company Approached Edison With Trading Tips,” *Dow-Jones Business News*, June 20, 2002; and “How Enron got game // Energy: Records show Perot Systems coached traders, including Edison, on market `options,” *Orange County Register*, 21 June 2002, 1.

<sup>24</sup> Technical Conference Transcript, Docket Nos. ER96-1663 *et al* Sept. 12, 1996, 37-47. The small consumers’ representative oddly noted that “we don’t let investors in land decide where the highways are going to be built.”

<sup>25</sup> 71 FERC ¶ 61,265 (Dec. 18, 1996), Slip Op. at 25. FERC requested a filing from the ISO rather than the three utilities who filed the original application.

On March 31, 1993 the PX and ISO made separate Phase II filings that outlined mitigation and monitoring in more detail.<sup>26</sup> Both would have internal employee-staffed MMIs and external committees entrusted with evaluation of reports by the internal MMIs and with the power to initiate investigations on their own. The external committees would be selected by the institutions' governing boards.<sup>27</sup> It was proposed that upon a finding of market power by an MMI the Governing Boards of the ISO and PX would have broad discretion about the disposition of the finding, including the ability to directly suspend a participant or levy fines without regulatory intervention.<sup>28</sup> Some commentators noted that the applications unnecessarily restricted monitoring to generation, with no clear way to investigate anticompetitive transmission activity that might result if the ISO were not truly independent.<sup>29</sup> Both an industrial user group and the CPUC complained that the plan gave no data access to outsiders who might wish to identify or confirm a specific instance of market power.<sup>30</sup> Others found the separation of the ISO and PX MMIs problematic, believing that coordinated plans might better detect abuses that

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<sup>26</sup> Pacific Gas & Electric Co. *et al*, The Phase II Filing of the California Power Exchange Corporation, Vol. 1, Docket Nos. EC96-19-001 *et al* (Mar. 31, 1997) ; California Independent System Operator Corporation's Phase II Tariff Filing, Docket Nos. EER96-1663 *et al* (Mar. 31, 1997). Southern California Edison, supposedly an entity at risk of exercising market power, oddly found the proposed monitoring plans so vague that they would not allow the early detection of anticompetitive activity. In particular, the company recommended that all suppliers and not just the three utilities should submit cost data . See Order Conditionally Authorizing Limited Operation of an [ISO and PX], Docket Nos. EC96-19-001 *et al* (Oct. 30, 1997) , Slip Op. at 234. ["Oct. 30 Order"]

<sup>27</sup> In response to the possibility that interests on the governing boards could suppress monitoring, the PX and ISO compliance divisions would have the power to refer reports to regulatory agencies without their boards permissions. *Id.* at 242.

<sup>28</sup> Response of the [ISO and PX] to Request for Additional Information, Docket No. ER96-1663 *et al*, May 20, 1997 at 36-38. The answers (at 41) also included a final attempt to have FERC impose mitigation on the federal Bonneville Power Administration, which the utilities believed had excessive market power.

<sup>29</sup> Comments of Coalition for a Competitive Electric Market [marketer group] and Turlock Irrigation District, Docket Nos. ER96-1663 *et al*, June 6, 1997. Likewise the Northern California Power Agency [a group of transmission-dependent municipal utilities] noted that gaming of the congestion or imbalance markets structure of generation] could produce windfall profits, particularly if undertaken with the help of derivatives. (Oct. 30 Order, *supra* note 26 at 228) NCPA was one of the few entities concerned about the possibility of market power by owners of divested generation.

<sup>30</sup> Comments of the Energy Producers and Users Group [refiners and petrochemicals] and CPUC and CPUC, June 6, 1997, Comments of the CPUC, July 8, 1997. This problem later came up (See Sec. IV.A *infra*) in an ISO Market Surveillance report alleging that generation owners were manipulating Reliability Must-Run generator contracts to raise PX prices. Citing confidentiality, generators were not allowed access to the data underlying the regression estimates on which the report's conclusions rested..

involved the two entities' markets simultaneously.<sup>31</sup> In reply, the ISO and PX rejected a single "Inspector General" on the basis that it would "unduly isolat[e] the monitoring function from the day-to-day operations of the ISO and PX." As regards disclosure of data, they promised to "explore" it. Responding to a criticism of the proposed enforcement powers, the PX and ISO noted that activism was "the overwhelming view in the WEPEX steering committee process, subsequently affirmed by the Governing Boards."<sup>32</sup>

On October 30, 1997 FERC conditionally authorized the opening of the ISO and PX at the start of 1998. It found that "the mitigation proposals, as modified, in conjunction with the monitoring/enforcement plan and Reliability Must-Run Agreements, adequately mitigate the Companies' generation market power for PX sales of energy."<sup>33</sup> Since generation divestiture would not happen immediately, mitigation measures would remain in place "until the companies file and we approve a proposal to remove them."<sup>34</sup> Noting that coordination between the ISO and PX monitors was "critical to successful market surveillance," FERC requested a filing to outline the details of their interactions.<sup>35</sup> It acknowledged that the plans were vague, but told the monitors to work out their methods after the market opened, and to investigate complaints by market participants with some thoroughness. The ISO and PX did not receive the ability to impose sanctions on their own, and were required to file any event they deemed to require sanctions at FERC for approval. It was recommended, as in antitrust, that monetary penalties be multiples of the guilty party's profits.<sup>36</sup>

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<sup>31</sup> Comments of Metropolitan Water District, June 6, 1997. The separation was defended as part of the general plan to avoid other market abuses by keeping the PX and ISO separate. (Reply Comments of the ISO, June 23, 1997 at 109) Again anticipating the issues discussed below, NCPA commented that "[m]arket participants could be significantly harmed by any entity that may control the forecast bidding of up to 40 percent of the load in any hour [i.e. one of the two large utilities] by intentionally over- or under-stating forecasted demand." With separation of the PX and ISO monitors this type of behavior and its price effects would be harder to detect. See Oct. 30 Opinion, *supra* note 26 at 228.

<sup>32</sup> Joint Reply Comments of the ISO and PX, June 23, 1997 at 112, 116, 122, and 128. Even at this late date the question of exactly who would be subject to monitoring had apparently yet to be answered. These comments proposed a technical conference to discuss Southern California Edison's suggestion that monitoring be extended beyond the three utilities to all other generators and intermediaries.

<sup>33</sup> Oct. 30 Opinion at 234.

<sup>34</sup> *Id.*

<sup>35</sup> *Id.* at 248.

<sup>36</sup> *Id.* at 249-251.

On October 31, 1997 the PX submitted its protocols in more detail. Continuing a standard of vagueness, its Compliance Unit was to see whether “markets are being manipulated to the detriment of their efficiency or fairness.” It would particularly search for “anomalous” behavior, defined as “depart[ing] significantly from the normal behavior in competitive markets...or as behavior leading to unusual or unexplained market outcomes.” A non-exhaustive list of anomalous behaviors included withholding of capacity that would “normally be offered in a competitive market,” as well as “unusual trades or transactions [and] pricing patterns that are inconsistent with prevailing supply and demand conditions.” “Gaming” was also prohibited, defined as “taking unfair advantage of the rules and procedures ... to the detriment of the efficiency of and of consumers [sic] in the PX markets.” It could also mean “taking undue advantage of other conditions that may affect the availability of transmission and generation capacity.”<sup>37</sup> The protocols were silent on the ability of the MMIs to monitor the integrity with which markets were administered or transmission allocated by nondiscriminatory methods.

### C. Interest groups and the formation of MMIs

With their voting monopoly, California’s three large corporate utilities clearly dominated the basic formulation of the ISO and PX. An objector to utility decisions would need to bear the costs of taking its problems to FERC during the certification process. To form complex institutions, a complex process is necessary. The elaborate committee process itself, however, favored participation by utilities, who would continue to have distribution monopolies whatever institutions finally took shape, and who would be able to recover their costs of participation as elements of their cost of service. There is no evidence prior to the utilities’ market power filings at FERC that any potential victim of monopoly expected that the CPUC and FERC would not be up to the task of monitoring competition. If in fact there were doubts about the regulators’ competency, there was no suggestion that a new entity was a better way to fill the gap than alterations to some existing regulatory body.

The vagueness of the responsibilities given to MMIs might better prepare them to identify and intervene in a wider range of market activities, but would also increase the likelihood that they would themselves become regulators in their own right and respond to demands that an activity that interested some particular market participant be investigated. Why there were four separate agencies, each with the power to institute an investigation, remains unclear. Such a polyarchic system increases the likelihood of investigations, both warranted and misguided, and the odds that a worthwhile matter will be examined. It also increases the likelihood that

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<sup>37</sup> Market Monitoring and Information Protocol, Transmittal of the California Power Exchange Corporation, Docket Nos. EC96-19-006 *et al*, Oct. 31, 1997 at 2 and 3. In April 2003 this language would be used by FERC to rationalize prosecution of certain transactions associated with Enron Corporation and other market participants that were not explicitly prohibited by the rules of the institutions. See Final Report on Price Manipulation in Western Markets, Docket No. PA02-2-000 (Mar. 2003) at VI-6.

resources will be dissipated on unwarranted investigations. (Sah and Stiglitz 1986) Economists were conspicuously absent in the entire process of MMI formation in California. Other than consultants for interested parties they were never seen offering public advice to regulators or discussing the question of surveillance designs among themselves professionally.

#### **IV. Virtual Bids**

##### A. Arbitrage and market power in two-settlement systems

Four of the five major ISO markets operating in the U.S. as of last year had encountered the issue of fictitious [“virtual”] bids by participants for the purpose of arbitraging between power markets with different closing times.<sup>38</sup> A comparison of the attitudes and actions of their MMIs toward virtual bids illustrates the potential importance of political factors. At one extreme, virtual bids by California non-utility generators and marketers served to counteract demand shifts by utilities among various markets that were intended to lower the utilities’ average power purchase prices. Virtual bids were viewed with great alarm (but not by operating personnel) and may yet serve as a basis for criminal prosecutions of some bidders. At the other extreme, virtual bidding was introduced in the PJM Interconnection without disputes at the same time its markets opened. PJM’s MMI endorsed its introduction and continue to certify its efficiency in annual reports to FERC. Between California and PJM lie New York and New England. The ranking of hostility to virtual bids among the regions reflects the situations of their utilities. California’s were facing a time limit on stranded cost recovery and a threat of insolvency, so allowing virtual bids to counter their demand shifts among the markets would significantly worsen their financial problems. PJM’s utilities were operating in markets under negotiated agreements that would recover their stranded costs according to preset schedules independently of market prices.

All four of these systems operate their markets under a two-settlement system. A day-ahead market (DAM) takes hourly bids, transmission constraints are factored in, and a set of hourly prices and schedule commitments are determined for the next day. The supply schedules may not match demand exactly in the next day, necessitating a real-time or imbalance market (RTM) in which a near-immediate energy price is determined by these shortfalls and excesses, along with generation and demand bids from entities that chose not to enter the day-ahead market.<sup>39</sup> One expects that if bidders are free to enter either market as buyers or sellers their

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<sup>38</sup> Markets operated by the Electricity Reliability Council of Texas (ERCOT) do not have a centralized PX.

<sup>39</sup> The text does not consider the further complications of ancillary services markets and the pricing of capacity and energy from generators dedicated to those services.

prices will converge, to the extent allowed in the face of uncertainty by the earlier closing of the DAM.

### B. California: prohibitions and insolvent utilities

California (when its PX was operating) frequently saw attempts by large utility purchasers to make the DAM (PX market) and RTM prices unequal by understating their expected loads in the DAM and making up the difference in the RTM. The utilities were under legal compulsion to use only the PX and ISO markets, and to recover their stranded costs within a fixed deadline in the difference between fluctuating energy market prices and frozen retail rates. On peak days when generation capacity is strained, those units with the highest marginal costs will operate. If their power is sold in the day-ahead market utilities' energy bills will rise disproportionately because the highest accepted supply bid sets the hourly price received by all sellers. The supply curve of California generation is quite flat until it approaches the limits of capacity, when it assumes the "hockey stick" form and becomes much steeper.<sup>40</sup> Thus on a peak day a utility buyer whose demand looms large in the PX might gain substantially by unilaterally understating its expected demand there.<sup>41</sup> The PX will then clear at a price on the flatter part of the supply curve, and the utility will make up its shortfall in the real-time market. The high-cost generation that would normally be traded through the PX will now only be priced in the real-time market, and the average energy costs of the large buyers will fall.

In California, demand migration by utilities became apparent early in the operation of its ISO and PX, in part as an aspect of more general difficulties with Reliability Must-Run (RMR) contracts made with generators whose operation was necessary to maintain system integrity. There were conflicts between the ISO's Market Surveillance Unit and generators regarding the prevalence of demand migration and its effects on efficiency.<sup>42</sup> The MMIs acknowledged that shifts between the markets were taking place, but its reports generally viewed them as manifesting the market power of the new owners of divested utility generation. The MMIs

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<sup>40</sup> The "supply curve" of California generators is graphed in Borenstein (2002, at 199). The supply to California actually originates all over the western interconnection. In an average year between 20 and 25 percent of power used in the state is imported.

<sup>41</sup> California's three large corporate utilities normally accounted for 80 to 90 percent of total load in the PX day-ahead market. Their demands were roughly in the proportion 50:40:10.

<sup>42</sup> The major issues of these complex proceedings are summed up in two documents out of many available in the dockets cited. ISO Market Surveillance Committee, Report of the Market Surveillance Committee on Redesign of markets for Ancillary Services and Real-Time Energy, April 6, 1999, at [www.caiso.com](http://www.caiso.com) and Supplemental Comments of Reliant Energy Power Generation, Inc. on the Report of the Market Surveillance Committee, Docket Nos. ER98-2843-007 *et al.* (April 19, 1999) and Attachment "RMR Contracts and the California PX Market" by the NorthBridge Group. The author filed comments in this proceeding on behalf of Dynegy, Inc.

expected that if competition actually prevailed, generators would be bidding into the two markets at their marginal expenses, while its critics asserted that the sequential nature of the markets meant that rational bids would equal opportunity costs.<sup>43</sup> In effect, bidding opportunity costs would arbitrage the two markets and ideally defeat the utilities' attempts to exercise market power. As energy prices rose during the 2000-2001 crisis period, the utilities were migrating as much as 30 percent of their demand between the markets. This migration was also a reflection of differences in ceiling prices allowed in the day-ahead and real-time markets. The PX ceiling was above \$2,000/MWh, while the real-time ceiling was at times as low as \$250 and was binding regardless of the amount of excess demand resulting from the migration of purchasers to it.<sup>44</sup>

The migration of demand to the real-time market posed problems for the ISO, since at the start of operations it was expected to normally account for no more than five percent of all power flowing through the ISO. When utilities "underscheduled" the ISO might face problems in finding available resources to fill the real-time gap. Other scheduling coordinators (marketers and independent producers) had incentives to arbitrage the system, but could only accomplish this by misrepresenting their own resources and demands. They would acquire resources in excess of their loads and bid the unused resources into the real-time market, lowering prices there and raising them in the day-ahead markets. This technique improved allocational efficiency and eased the ISO's task of coping with the utilities' understatement of demands. This behavior by scheduling coordinators was detailed as one of their diverse manipulative trades in subsequent FERC proceedings on the these markets.

The non-utilities were making what in other ISOs were called virtual bids. The same effect could have occurred under a sanctioned regime of virtual bidding. To make a virtual bid an agent (who need not be a producer, marketer, or user of electricity) can offer to buy or sell power in one of the markets and then reverse the transaction at the RTM price, buying back the obligation to supply or selling back promised demand. Holders of commitments to buy or sell can use virtual bids to hedge their risks. If virtual bidding is deep enough it can provide liquidity in markets that would otherwise be far thinner because they are used solely by purchasers and producers of power for actual delivery. Virtual bidding is not without risk because the price at which one can do the real-time part of the transaction may bring the bidder a loss. Virtual bidding in practice makes operations more predictable, while making the migration of large

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<sup>43</sup> In fact the sequential nature of the markets is far more complex. Quan and Michaels (2001) estimate that in the average day a bidder must make several hundred choices, many of which are irreversible only at a cost.

<sup>44</sup> "Cal-ISO May Become Big Player in Forward Markets," *Megawatt Daily*, Sept. 8, 2000. Utility and ISO representatives at times claimed the destabilization was due to the fact that generators had been the initiators of the migration. Why generators would want to move their supplies from a market with a non-binding price cap to one with a binding cap was never made clear. "Despite Concern that Underscheduling Imperils Grid, Cal-ISO Snubs Potential Fix," *Power Markets Week*, Aug. 28, 2000, 3.

demanders to the real time market riskier. In December 2000 FERC attempted to control underscheduling at the PX by instituting a cumulative penalty on utilities engaging in it. Over the succeeding months the utilities incurred over \$1 billion in penalties. In December 2001 FERC set them to zero retroactively and abandoned the December 2000 rule.<sup>45</sup>

California's ISO and its MMIs continued to view activities of generators as anticompetitive until prices returned to more normal levels in mid-2002. By that date the two largest utilities were insolvent or bankrupt and state government had taken over their purchasing activities. In any case the opportunities no longer existed because the PX ceased operating and filed for bankruptcy in January 2001. Nevertheless the demand migration and underscheduling have remained before FERC as part of its more comprehensive investigations of California markets and the calculation of refunds on allegedly unjust and unreasonable prices. The head of the ISO's Market Surveillance Committee testified on behalf of the "California Parties" at FERC in the refund proceeding (parallel to California's) that covered the Pacific Northwest. The California parties normally included the ISO, the state Electricity Oversight Board, the state Attorney General, and the three corporate utilities seeking refunds.<sup>46</sup> The ISO's charter and regulations allow its market monitors to work for interested parties at the discretion of the organization.

FERC staff's final report on the California market included analyses of questionable market conduct and trading practices.<sup>47</sup> The report said that demand migration by the utilities in order to lower their power costs was unambiguously an exercise of market power, no different in kind from the counter-migration by generators. FERC staff, however, concluded that the generators had incurred liability because they had exercised market power and moved prices in an attempt to profit. At the same time it relieved the utilities of liability on the odd grounds that their motive in migrating demand was to lower costs rather than increase revenues.<sup>48</sup>

### C. New York: strategies of delay

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<sup>45</sup> Order Directing Remedies, *supra* note 14 at 42, San Diego Gas and Electric Co., Order on Clarification and Rehearing (Dec. 19, 2001), 97 FERC ¶ 61,275, Slip Op. at 114.

<sup>46</sup> For this docket the three corporate utilities and the ISO were not listed among the California Parties. See California Parties Forward Direct Testimonies of Frank Wolak and William Green in Docket No. EL01-10, Submittal 20010828-0360 (Aug. 28, 2001); Prepared Direct Testimony of Frank A. Wolak PhD, Docket No. EL01-10-000 (Aug. 17, 2001).

<sup>47</sup> See Final Report on Price Manipulation, *supra* note 37, Ch. VI.

<sup>48</sup> *Id.* at VI-21–VI-25. The full FERC has yet to render a final ruling on liabilities and refund amounts.

## 1. Restructuring and stranded cost

New York's restructuring began with the phasing-in of retail competition between 1996 and 1999, accompanied by settlement agreements for individual utilities. The utilities divested 91 percent of their generation, but each could still contract bilaterally as well as using the markets put in place by the New York ISO (NYISO).<sup>49</sup> During the transition utilities faced rate freezes, with added uncertainty resulting from the relegation of stranded cost issues to future ratemakings. New York's billing credit provisions for departing retail customers were less liberal than PJM's, resulting in under 5 percent of its loads leaving utility service. The state's eight large utilities, generally high-cost systems, thus dominated purchases at the NYISO's markets. They had a common interest in keeping energy prices low, both to ensure recovery of their stranded costs and their longer-term attractiveness as retail suppliers.

The NYISO's markets began operation in December 1999, concurrent with the ISO's taking over the functions of the New York Power Pool. Approximately 50 percent of the power passing through the ISO is bilateral contracts, 45 percent is day-ahead, and 5 percent is real-time. Summer peak load in 2001 was 30,983 MW.<sup>50</sup> The NYISO has an internal Market Monitoring Unit and an external "Independent Market Advisor." At the outset, the NYISO accepted only bids for physical supply to meet forecast demand, and only in the day-ahead market (DAM). These bids are then passed through a congestion and security check to determine locational day-ahead settlement prices. The NYISO also accepts capacity and energy bids for ancillary services, and the price of this energy is determined in the real-time market (RTM). At the start, generators could only bid into the DAM, while loads could choose whether to bid into it or the RTM. Beginning in July 2001 the NYISO introduced price-capped load bidding, which allows a load-serving entity to specify a quantity of load it will remove from the DAM if price there exceeds a chosen value. The load can be sent to the RTM, or it may be a price-sensitive load that can be cut.<sup>51</sup>

NYISO initially stated that it would introduce virtual bids after its first summer of operation, on grounds that it should make certain existing software and protocols were working

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<sup>49</sup> New York State Electricity Markets, FERC Market Design Technical Conference (Jan. 22, 2002), presentation graphics at 6. [http://www.nyiso.com/topics/miscellaneous/nyc\\_elec\\_mkts\\_ferc\\_tech\\_conf\\_01\\_22\\_02.pdf](http://www.nyiso.com/topics/miscellaneous/nyc_elec_mkts_ferc_tech_conf_01_22_02.pdf)

<sup>50</sup> NYISO Structure, LBMP Concepts, and the 2 Settlements, presentation graphics (Oct. 29, 2001) at 4. <http://www.nyiso.com/services/training/nymoc/index.html>

<sup>51</sup> New York State Electricity Markets, *supra* note 49 at 45. Software difficulties appear to explain the delay in introducing this utility-supported technique. [http://www.nyiso.com/topics/miscellaneous/nyc\\_elec\\_mkts\\_ferc\\_tech\\_conf\\_01\\_22\\_02.pdf](http://www.nyiso.com/topics/miscellaneous/nyc_elec_mkts_ferc_tech_conf_01_22_02.pdf)

properly before introducing new transactions and participants.<sup>52</sup> In July 2000 Morgan Stanley Capital Group asked FERC for expedited removal of NYISO's restriction on non-physical market participation, claiming that the markets were inefficient and that the exclusion of virtual transactors discouraged trading and reduced liquidity.<sup>53</sup> It submitted data showing that in the New York City load zone DAM prices exceeded RTM prices by an average of \$7.27/MWh.<sup>54</sup> NYISO responded with additional claims of delay in scheduling practices and software, and introduced data showing that over the entire period of its operation the DAM price premium was only \$4.74/MWh.<sup>55</sup> Possibly unaware of utilities' interest in low prices, NYISO's Independent Market Advisor asked why physical transactions alone would not arbitrage the markets, and raised the possibility that more bidders might make prices more volatile and more divergent.<sup>56</sup> In October FERC rejected Morgan Stanley's complaint, requesting little more from the ISO than a progress report by January.<sup>57</sup>

NYISO's September 2000 compliance filing at FERC included figures from its internal market monitor showing that average prices had further diverged to a \$6.17 DAM premium.<sup>58</sup> Without evidence, NYISO maintained that virtual bidding would not erase the difference, but acknowledged that its introduction would leave markets "enhanced." It also believed that additional delays were needed to avoid "severe financial and reliability consequences if the linkages between the existing 'totally physical' and the to-be-created financial markets are not constructed properly."<sup>59</sup> Enron countered by observing that PJM had instituted virtual bidding with apparent success on the same June date as it opened its RTM. Enron was also the first

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<sup>52</sup> New York Independent System Operator Inc.'s Answer to Morgan Stanley Capital Group Inc.'s Complaint and Request for Fast-Track Processing, Docket No. EL00-90-000 (July 17, 2000).

<sup>53</sup> Complaint and Request for Fast-Track Processing of Morgan Stanley Capital Group Inc., Docket No. EL00-90-000 (July 5, 2000).

<sup>54</sup> *Id.*, Att. B. One suspects that the choice was not random. Both the DAM and RTM had operated for a longer time and they determined hourly prices, probably a better test of an arbitrage hypothesis. Morgan Stanley's sample was only for deliveries in the most transmission-constrained area of the state, where one would expect more anomalies because of limits on power flows that might otherwise eliminate price differences.

<sup>55</sup> NYISO Answer, *supra* note 52 at 8, 11, and Att. V.

<sup>56</sup> *Id.*, Att. VI at 3.

<sup>57</sup> Morgan Stanley Capital Group, Inc., v. New York Independent System Operator Inc., Docket No. EL00-90-000, Order on Complaint, 93 FERC ¶ 61,017 (Oct. 5, 2000).

<sup>58</sup> New York Independent System Operator, Inc.'s Combined Compliance Filing and Report, Docket No. ER00-3591-000 (Sept. 1, 2000), Att. VI at 7.

<sup>59</sup> *Id.* At 55.

intervenor to assert that convergence would improve because virtual bids were a defense against the market power of purchasing utilities.<sup>60</sup>

Consolidated Edison's reply favored a moratorium on virtual bidding in light of what it viewed as more serious software and protocol problems, but the company did argue that software modifications to permit price-capped load bids by utilities were "urgent." It said that the bids "will provide some protection to the load serving entities by giving them the opportunity to meet their energy requirements in the RTM." The company further claimed (without citing any authority) that RTM bids exceeding DAM bids were evidence of sellers' market power and that RTM bids should be capped at DAM prices.<sup>61</sup>

NYISO submitted its progress report to FERC in February, a month late.<sup>62</sup> Its staff explained that a quick implementation of virtual bidding was not in the offing since without thorough testing there might be reliability problems and "market anomalies." Virtual bidding would have to wait until November, but zonal price-capped load bidding by utilities would start earlier (July 1), because it was a necessary part of summer demand management policy. NYISO's staff recognized that virtual bidding might serve to counter strategic underbidding by utilities, but said that the organization's market monitors had not detected any evidence of such behavior to date.<sup>63</sup> The monitors had no separate explanation for the persistent price divergence.

## 2. NYISO's internal processes

In late 2000 NYISO's Market Structure Working Group, a subgroup of its Business Issues Committee, formed a Virtual Bidding Volunteer Group whose first project was to determine whether underbidding actually affected prices. Using ISO dispatch software to examine bidding that deviated from forecast load, it found "more than a one-to-one relationship between total [day-ahead] energy cost and bid load." i.e. "A decrease in DA bid load results [in] a still larger decrease in total DA energy cost." On a moderate load day a 9 percent day-ahead underbid reduced total day-ahead energy cost by 21.5 percent, while on a high load day a 6

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<sup>60</sup> Motion to Intervene Out of Time and Comments of Enron Power Marketing, Inc., Docket No. ER00-3591-000 (Sept. 29, 2000) at 8.

<sup>61</sup> Motion to Intervene, Answer, and Comments of Consolidated Edison Company, Docket No. ER00-3591-000 (Sept. 27, 2000) at 11 and 17.

<sup>62</sup> New York Independent System Operator Inc.'s Report on the Implementation of Virtual Bidding and Zonal Price-Capped Bidding, Docket No. EL00-90-000 (Feb. 2, 2001).

<sup>63</sup> *Id.*, Att. A at 2.

percent underbid led to a 23 percent decrease in that cost.<sup>64</sup> Unless movement of the underbid load to the RTM results in astronomical price increases there, underbidding in the DAM is rational for utilities, particularly on peak days.

On Dec. 12, 2000 NYISO's Business Issues Committee met. A motion for simultaneous introduction of price-capped load bids and virtual bidding for everyone in fall of 2001 was replaced by an amended motion to introduce only price-capped load bids by summer of 2001. The minutes indicate concern that absent virtual bidding the introduction of load bidding alone "could create an unfair advantage for some at the expense of others." The amended motion passed with 65.06 affirmative votes.<sup>65</sup> The winning bloc was made up of "transmission owners" (i.e. utilities), large end-users, small consumers, state power authorities, and municipal utilities. "Generation owners" (i.e. non-utility power producers) unanimously opposed it, while "other suppliers" (a mix of independent and utility-affiliated marketers) were split.<sup>66</sup>

With virtual bidding becoming a more real threat, utilities raised concerns of gaming. ConEd noted that if the expected RTM price was low, virtual bidders would attempt to raise the DAM price but utilities could still migrate load to the RTM using price-capped load bids. Since ConEd viewed the RTM as a "dead end for load," it believed that curbing market power there was very important.<sup>67</sup> ConEd proposed some regulatory remedies. If in fact utilities were able to move the DAM price, they could keep it there with rules that limited the rights of counter-bidders. Specifically, ConEd proposed an early close to RTM bidding (6 PM on the prior day) to "minimize the ability of generators to opportunistically adjust bids in real-time due to changing system conditions for which physical load has little protection from the potential of market abuse." The company also favored a transitional cap on total virtual bidding (PJM had such a

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<sup>64</sup> NYISO, Virtual Bidding Volunteer Group Presentation to Market Structures Working Group, Dec. 6, 2000, unnumbered. This study never turns up again as virtual bidding progresses through the NYISO. Note that it was not performed by the ISO's internal or external MMI.  
[http://www.nyiso.com/services/documents/groups/bic\\_mkt\\_struct\\_group/12\\_06\\_00/virtual\\_bidding\\_in\\_nyiso.pdf](http://www.nyiso.com/services/documents/groups/bic_mkt_struct_group/12_06_00/virtual_bidding_in_nyiso.pdf)

<sup>65</sup> Minutes of NYISO Business Issues Committee Meeting, Dec.12, 2000 at 5. The allocation of votes to interest groups on the major ISO committees was the outcome of a lengthy series of applications to FERC and renegotiations over rejected applications, hence the two decimal places that weight the vote shares.  
[http://www.nyiso.com/services/documents/groups/bus\\_issue\\_comm/final\\_minutes\\_2000/bic\\_final\\_minutes\\_121200.pdf](http://www.nyiso.com/services/documents/groups/bus_issue_comm/final_minutes_2000/bic_final_minutes_121200.pdf)

<sup>66</sup> *Id.*, unnumbered.

<sup>67</sup> Consolidated Edison Company of New York, Inc., Virtual Bidding Comments on Market Structure and Issues, submitted to NYISO (Mar. 30, 2001) at 7.  
[http://www.nyiso.com/services/documents/groups/bic\\_virtual\\_load\\_bid\\_grp/04\\_02\\_01/coned\\_proposal.pdf](http://www.nyiso.com/services/documents/groups/bic_virtual_load_bid_grp/04_02_01/coned_proposal.pdf)

cap), and a requirement that all load bids be identified as physical or virtual.<sup>68</sup> It also favored lengthy software testing and educational campaigns, noting that “load-serving entities, and therefore the consumers in New York, stand to be significantly harmed if they are not adequately aware of the changed marketplace and how their bidding habits must be *modified*.”<sup>69</sup> ConEd also wanted tough creditworthiness requirements for virtual bidders, citing California as an example.<sup>70</sup>

### 3. The FERC process continues

Shortly after NYISO’s February 2001 progress report, Morgan Stanley again requested that FERC order virtual bidding for the upcoming summer rather than wait until fall. Its rationales included a claim that virtual bidding would “facilitate NYISO’s avoidance of price and supply issues that threatened it last summer and that continue to plague California.”<sup>71</sup> Enron’s protest referenced a document by the Market Structures Working Group which stated that utilities in reality were already engaged in implicit virtual bidding whenever their day-ahead load bids did not equal their realized loads.<sup>72</sup> NYISO responded that its market monitors were on the lookout for underbidding and had not yet found any, while noting that virtual bidding would still be a useful tool to fight underbidding.<sup>73</sup> The New York Public Service Commission’s testimony stood the argument on its head, telling FERC that generators could already arbitrage the markets, apparently by using existing loopholes to shift their bids, while generators somehow could not. Without mentioning underscheduling by utilities, the PSC did support price-capped load bidding, which it claimed would end the “distinct disadvantage” of buyers.<sup>74</sup>

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<sup>68</sup> *Id.* at 9, 11-12. There was no discussion of how to apportion rights when total desired virtual bids exceed the limit.

<sup>69</sup> *Id.* (emphasis lacking in original).

<sup>70</sup> This is odd, because in California it was utilities that were the first to lose their creditworthiness.

<sup>71</sup> Morgan Stanley Capital Group, Inc. Motion for Immediate Commission Action Regarding Virtual Bidding Implementation Schedule, Docket No. EL00-90-000 (Mar. 5, 2001) at 3.

<sup>72</sup> Corrected Protest of Enron Power Marketing, Inc., Docket No. EL00-90-000 (Mar. 6, 2001), citing Virtual Bidding Volunteer Group, *supra* note 64

<sup>73</sup> New York Independent System Operator Inc.’s Answer to Morgan Stanley Capital Group Inc.’s Motion for Immediate Commission Action, Docket No. EL00-90-000 (Mar. 20, 2001) at 6. If in fact they exist, no MMU studies of underbidding have been found.

<sup>74</sup> Answer of the New York Public Service Commission to the Motion for Immediate Commission Action, Docket No. EL00-90-000 (Mar. 20, 2001) at 4.

On Sept. 4, 2001 the ISO filed at FERC the tariff modifications that would allow virtual bidding. On October 25, they were accepted, with changes ordered to lower the high collateral requirement NYISO had imposed on virtual bidders to the same level as its requirement on physical bidders.<sup>75</sup> FERC cut virtual bidding collateral from fourteen days of exposure to seven, but refused to alter what intervenors claimed were excessively arbitrary provisions on mitigating market power. Although it clearly understood the efficiency of virtual trading, FERC rationalized its language on grounds that “initially the potential for market implementation flaws warrants a broader level of NYISO’s control over the virtual market.”<sup>76</sup> Regarding credit exposures, during the first two months of virtual bidding the total credit exposure of virtual bidders on a net portfolio basis was less than 1 percent of posted collateral.<sup>77</sup>

#### 4. The effects of virtual bidding

Shortly before the opening of virtual bids, NYISO’s Market Monitoring Unit tried to determine the effects of virtual bidding on security-constrained dispatch, and found that all of the relevant changes were small and in the expected directions. It summarized its study by stating that “no anomalous market responses were found,” and that [t]he NY market is more robust and harder to manipulate with virtual bidding than feared.”<sup>78</sup> Since bidding opened, there has been only one available NYISO report to FERC, filed on May 30, 2002. There were 24 virtual transactors, whose average gross daily volume was 9.7 percent of NYISO load.<sup>79</sup> An attached report from the MMU “suggests] that virtual bidding has fostered price convergence...the price delta over most of this period has hovered close to zero.”<sup>80</sup> The geography of virtual bids is consistent with efficiency, and so is its hourly pattern. The transmission-constrained New York City and Long Island areas accounted for 83 percent of virtual load bids, while the most active virtual supply bid zone was the Hudson valley (47 percent of the total), immediately to the north. Virtual load bids usually peak between 4 and 5 PM because RTM prices are consistently higher

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<sup>75</sup> New York Independent System Operator, Inc., Order Accepting Virtual Bidding Proposal and Mitigation Measures, and Directing Compliance Filing, 97 FERC ¶61,091 (Oct. 25, 2001).

<sup>76</sup> *Id.* at 7.

<sup>77</sup> Motion to Intervene and Comments of Member Systems, Docket Nos. ER01-3009-007 *et al.*, (May 22, 2002) at 4.

<sup>78</sup> Virtual Bidding Market Test, Business Issues Committee, Oct. 25, 2001, unnumbered. [http://www.nyiso.com/services/documents/groups/bic\\_mkt\\_struct\\_group/10\\_23\\_01/virt\\_bid\\_mkt\\_test.pdf](http://www.nyiso.com/services/documents/groups/bic_mkt_struct_group/10_23_01/virt_bid_mkt_test.pdf)

<sup>79</sup> New York Independent System Operator Inc.’s Report on Virtual Transactions in Docket Nos. ER01-3009-000 *et al.* (May 30, 2002) at 2.

<sup>80</sup> *Id.*, Att. A, unnumbered.

than DAM prices during that hour. Virtual supply peaks from noon to 1 PM because RTM prices are consistently higher than DAM prices then. The report concluded that “preliminary evidence suggests prices are converging in some hours.”<sup>81</sup>

The Independent Market Advisor estimated that during the first four months of the program there had probably been enough virtual bidding to thwart moderate attempts to exercise market power, if such attempts had been made. He drew this conclusion by noting that while some bids were clearly out of the money, enough are made at prices in the range where the effects of market power would most likely be seen.<sup>82</sup> The net effect of virtual bidding has thus far been to raise total volumes in the DAM, due to the fact that virtual loads exceed virtual supplies, although virtual load bids also reduce the volume of accepted price-capped physical load bids. The competitiveness is evident in that the “vast majority” of virtual bids and offers have been “price sensitive, i.e. most of the *unaccepted* quantities have been at bid prices close to market clearing levels.”<sup>83</sup>

The NYISO’s MMU has a program of monitoring and mitigating virtual bids, but has yet to impose the policy on any virtual bidder. NYISO itself is now remarkably open regarding the methods virtual bidders can use to influence market price. One set of training materials shows how a “little guy” (price-taker) can profit by examining patterns of DAM/RTM spreads and making appropriate virtual bids. The example, however, requires perfect hindsight. More interesting is the scenario for a “big guy,” whose “strategy is to manipulate [nodal prices]” Graphics include one that shows how a virtual supply bid adds a horizontal portion to the market supply curve and “creates a flat spot, in other words a price ceiling.” Likewise, a high-price virtual load bid “[moves the load curve to the right. Peak hiking. Inflates clearing price. Profitable V. settlement? Maybe.” The exposition goes on to note that “opportunistic [high-price virtual supply] bids are seldom accepted, [while] manipulative [high-price virtual demand] bids are seldom rejected,”<sup>84</sup> leaving individuals to decide what intermediate bid strategies are worth

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<sup>81</sup> Virtual Transaction Market, Market Overview and Proposal to Modify Collateral Requirements, Management Committee Meeting, Feb. 7, 2002 at 12.  
[http://www.nyiso.com/services/documents/groups/mgmt\\_comm/02\\_07\\_02/agenda9\\_virt\\_trans\\_mkt.pdf](http://www.nyiso.com/services/documents/groups/mgmt_comm/02_07_02/agenda9_virt_trans_mkt.pdf)

<sup>82</sup> Affidavit of David B. Patton, Independent Market Advisor to NYISO and ISO-New England, Docket Nos. ER01-3155-000 *et al* (Mar. 19, 2002), at 36.

<sup>83</sup> David B. Patton, 2001 Annual Report on the New York Electricity Markets, presented to NYISO Board of Directors, April 16, 2002 at 39.  
[http://www.nyiso.com/services/documents/groups/mgmt\\_comm/04\\_16\\_02/2001\\_annual\\_report\\_final.pdf](http://www.nyiso.com/services/documents/groups/mgmt_comm/04_16_02/2001_annual_report_final.pdf)

<sup>84</sup> “Virtual Bidding Impact,” NYISO Training Materials, presentation graphics, Oct. 2001, unnumbered. [http://www.nyiso.com/services/training/virtual\\_bid/bid\\_impact%20illustra.pdf](http://www.nyiso.com/services/training/virtual_bid/bid_impact%20illustra.pdf)

following. A companion training document entitled “How to Place Virtual Bids” has a pile of gold bars and pair of dice on its first graphic.<sup>85</sup>

#### D. New England: heterogeneity and substitutes

The New England Power Pool existed for decades as a central dispatch and clearing arrangement for the region’s numerous utilities. Stranded cost issues are relatively minor for most utilities in the area, despite the introduction of retail competition in some states, most notably Massachusetts. They are minor because regulators in those states have set “standard offer” rates for incumbent utilities at such low levels that few customers have switched suppliers. A regional energy market began in 1999 as a single-settlement system for “residual” energy transfers between utilities whose generation was excessive or insufficient.<sup>86</sup> Another part of the slowness to adopt virtual bidding has been the fact that congestion costs are paid on an “uplift” basis that produces benefits and costs with consistency for particular utilities. Soon after the market began operating, stakeholders began planning a day-ahead / real-time system with nodal prices that would include virtual bidding. Difficulties in reaching agreement led to delays in filing at FERC, which lengthened when changes in policy required that New England’s market design be consistent with PJM and NYISO. FERC is currently considering the revised application, which will include both virtual supply and demand bidding.

Under the rules of the regional market, generators (mostly utility-owned) could affect the real-time price (which governs all settlements) by strategic bid withdrawals or last-minute exports and imports. Compounding the problem, NEPOOL did not use locational pricing to account for transmission congestion (concentrated in the Boston area) and instead socialized these costs in an “uplift” charge prorated among load-serving entities. At about the same time as markets opened, ISO New England (ISO-NE) came into existence as operator of the system and began presiding over market redesign. A committee of specialists within ISO-NE recommended that management institute a combined congestion management system and multi-settlement system, i.e. one with a DAM and an RTM. The committee viewed virtual transactions as

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<sup>85</sup> [http://www.nyiso.com/services/training/virtual\\_bid/user\\_functions.pdf](http://www.nyiso.com/services/training/virtual_bid/user_functions.pdf)

<sup>86</sup> During its first year of operation, this market handled 15.92 percent of the region’s power. See ISO-NE Annual Market Report May 1999-April 2000 at 19.

valuable for arbitrage, liquidity, and reliability.<sup>87</sup> Most of members of the relevant subcommittee, however, supported virtual demand bids, but not virtual supply bids.<sup>88</sup>

Shortly afterwards, a consultant to Enron urged the committee to reconsider allowing virtual supply offers.<sup>89</sup> In his view virtual supply eliminated an asymmetry by allowing the same set of DAM bids to both owners and non-owners of generation, allowing either to set the price. Virtual supply could mitigate generator market power, and the information conveyed by virtual bids would improve the accuracy of expectations about the real-time market. Regarding reliability, New England's generator commitment protocols were designed to be independent of bidder behavior, and scheduling problems associated with virtual supply would be no different from those arising whenever schedules did not match loads exactly. Finally, the consultant rejected suggestions that contracts-for-differences might substitute for virtual supplies, since they were limited to transactions with an identifiable generator as counterparty and were incapable of affecting market-clearing prices.<sup>90</sup>

At the end of March 2000 FERC received rival proposals from ISO-NE and a group of generation owners, both of which recommended virtual demand bids but not virtual supplies.<sup>91</sup> Generators said little about the price effects of virtual bids, preferring to argue that virtual supply "would add considerable uncertainty in the evaluation of system reliability" because the DAM's unit commitment procedures imposed binding obligations on accepted bidders.<sup>92</sup> The ISO went

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<sup>87</sup> Physical vs. Financial Transactions, Discussions of Scheduling Working Group (June 10, 1999), presentation graphics.  
[http://www.iso-ne.com/cmsmss/Historical\\_Data/CMS\\_Background\\_Documents/physical\\_vs\\_financial\\_transactions.ppt](http://www.iso-ne.com/cmsmss/Historical_Data/CMS_Background_Documents/physical_vs_financial_transactions.ppt)

<sup>88</sup> Scheduling Working Group Minutes (June 14, 1999) at 1.  
[http://www.iso-ne.com/cmsmss/Historical\\_Data/CMS\\_Background\\_Documents/Scheduling%20Working%20Group%20Minutes%2006-14-99.doc](http://www.iso-ne.com/cmsmss/Historical_Data/CMS_Background_Documents/Scheduling%20Working%20Group%20Minutes%2006-14-99.doc)

<sup>89</sup> Virtual Supply Offers in the Day Ahead Market (July 20, 1999), presentation graphics. The consultant, Scott Englander, is a Vice-President at Tabors Caramanis & Associates, with whom the author is affiliated. [http://www.iso-ne.com/cmsmss/Historical\\_Data/CMS\\_Background\\_Documents/virtual%20Supply%207-20-99b.pdf](http://www.iso-ne.com/cmsmss/Historical_Data/CMS_Background_Documents/virtual%20Supply%207-20-99b.pdf)

<sup>90</sup> *Id.* at 3 and 10-13.

<sup>91</sup> Filing of ISO New England, Inc., docket Nos. EL00-62-000 and ER00-2052-000 (Mar. 31, 2000); filing of Supporting Generators, Docket N. ER99-2335-000 (Mar. 30, 2000). Their major differences were on the format of bids (one-part or three) and certain aspects of locational pricing.

<sup>92</sup> Generators' Proposal, Ex. SG-1 at 6. ISO-Ne (at 39) also noted that virtual demand was in principle unneeded because physical shifts could achieve the same purpose, but that the latter might

(continued...)

on to note that virtual loads, by contrast, are matched by physical generation and their presence might even improve reliability. It also noted that there were roundabout methods of getting the same outcome that a virtual supply transaction would produce.<sup>93</sup> On June 28, 2000 FERC partially approved ISO-NE's proposal, citing reasons given by both the ISO and the generators for rejecting virtual supplies.<sup>94</sup> Note that this was FERC's first approval of any actual virtual bidding system. Virtual bidding, however, had yet to be instituted because the ISO expected an 18 to 24 month delay in preparing both the congestion market and two-settlement software.<sup>95</sup> On July 12, 2002 ISO-NE and NEPOOL jointly filed at FERC for a new market design, complete with virtual supply and demand bids. On Sept. 20, 2002, FERC accepted most of that application.<sup>96</sup>

#### E. PJM: an easy consensus for efficiency

The PJM Interconnection centrally dispatches generation and operates markets, and is the largest interconnected utility system in the world. In November 1997 FERC generally approved PJM's market proposals and certified it as an ISO.<sup>97</sup> Locational Marginal Pricing (LMP) of transmission began on April 1, 1998, while PJM was still dispatching its system on the basis of generator costs rather than bids. Even before the markets opened, PJM's MMI (an internal group) and its outside consultants expressed concern about insufficient liquidity in the DAM and

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<sup>92</sup>(...continued)  
interfere with security and congestion management.

<sup>93</sup> ISO Proposal at 43. Buyers who cannot arbitrage by bidding virtual supplies into the DAM can get the same effect by submitting a capped demand bid there and covering their load in the RTM if the DAM price is too high. Those who are not consumers can enter contracts with consumers that will settle at the DAM or RTM price as they choose.

<sup>94</sup> Order Conditionally Accepting congestion Management and Multi-Settlement Systems, 91 FERC ¶ 61,311 (June 28, 2000).

<sup>95</sup> FERC OK's ISO New England Power Grid Congestion Rules, Dow-Jones Energy Service, June 28, 2000.

<sup>96</sup> Order accepting in part and modifying in part Standard Market Design Filing and dismissing compliance filing re New England Power Pool et al, Docket Nos. ER02-2330 et al (Sept. 20, 2002).

<sup>97</sup> FERC approves PJM Majority's ISO and Congestion Pricing Proposal, *Foster Electric Report*, Dec. 3, 1997, 1.

in the forthcoming market for “firm transmission rights” to congestion revenue (“FTR”).<sup>98</sup> On Feb. 11, 1999 FERC found itself in agreement with PJM’s proposed markets and its FTR auction. Nevertheless the Commission rejected the application because of concerns that PJM was not doing all it could to help market participants manage the risks inherent in an LMP system.<sup>99</sup> It is then that virtual bids first came under consideration, and both supply and demand bids (known here as inc and dec bids) were included in PJM’s March 2000 submittal that provided details and modifications of its original proposal.<sup>100</sup> On June 1, 2000 the two-settlement system began operation with no recorded problems.

PJM also quickly resolved problems arising from the interaction of virtual bids and the creation of congestion. On September 12, 2000 an internal working group proposed a rule. “If a party makes both increment offers and decrement bids at the same [location], the bids/offers will not be permitted to set price if all or part of the bid/offer would not have been accepted but for some or all of the counter bid.”<sup>101</sup> On October 4, PJM’s Energy Market Committee voted unanimously for the rule, and on December 22 its policy-setting Members’ Committee did likewise.<sup>102</sup> Since then, the only rule change affecting virtual bids has been to allow negative decrement bids, effective June 25, 2002.<sup>103</sup>

In 2001 PJM’s DAM and RTM handled 15 percent and 6 percent of average on-peak load of 29,320 MW. Average on-peak inc (virtual supply) offers were 8,094 MW and dec (virtual demand) bids were 5,383 MW. PJM’s MMU believed that in addition to arbitraging the DAM and RTM, they were responsible for the growth of FTR auction activity and the increased numbers of FTR bids cleared during the later months of 2000.<sup>104</sup> Virtual bids have had no effect on PJM’s overall operating costs, and following the above tariff changes (and some others

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<sup>98</sup> PJM Market Monitoring Unit (MMU), PJM Interconnection State of the Market Report 2001 (June 2002) at 1.

<sup>99</sup> Order Rejecting Filings and Providing Guidance, and Directing New Filings, Docket Nos. ER98-1581-000 *et al* (Feb. 11, 1999), 86 FERC ¶61,147.

<sup>100</sup> Letter of Filing and Modifications of Tariff sheets, Docket No. ER00-1849-000 (Mar. 10, 2000).

<sup>101</sup> Two-Settlement working Group Agenda, Sept. 10, 2000, unnumbered, Meeting Notes, Sept. 12, 2000 at 2.

<sup>102</sup> Filing Letter and Redlined Tariff Sheets, docket No. ER01-773-000 (Dec. 22, 2000), Notice of Filing, Docket No. ER01-773-000 (Jan. 3, 2001).

<sup>103</sup> PJM Information Messages, June 13, 2002, unnumbered.  
<http://www.pjm.com/about/news/customer/custinfo.html>

<sup>104</sup> State of the Market Report 2001, *supra* note 98 at 42-47, 86-89.

affecting FTRs) there have been no further instances of concern about virtual bids as gaming tools. Instead, PJM views incs and decs as integral to the functioning of its markets.

Q.26. Will PJM Market Monitoring be reviewing excessive use of increment offers and decrement bids?

A. It is expected that the strong financial implications of submitting binding increment offers and decrement bids will provide enough incentive for participants to use them appropriately. As with all area[s] of the PJM Market, the PJM Market Monitoring Unit will have oversight of the two-settlement system implementation.

Q.27. Could the day-ahead market function without increment offers and decrement bids?

A. No, these features are financial instruments to allow participants to exercise a variety of price certainty options and risk management techniques. This is necessary for a robust market.<sup>105</sup>

#### F. Plausible Conclusions

Any generalization from four ISOs is hazardous at best. The degree to which virtual bidding was accepted and the resistance to its acceptance, however, is consistent with the broad outlines of an interest-group model of regulation. The largest resistance to virtual bidding should have occurred in California, and the smallest in PJM, with New York and New England between them.

California's three corporate utilities together served approximately 75 percent of the state. The smallest of them, SDGE, played a lesser role in the formation of the institutions than the two large systems, and in any case it was able to divest its plants at sufficient premiums that it had recovered its stranded costs by late 1999, before the price crisis broke. The legislative bargain required that they collect their stranded costs by a firm deadline, and to be entirely dependent on the PX and ISO in the process. Well before the price rise began in spring of 2000, they were shifting demands among the markets to lower their costs. They had the most to lose if virtual bidding became standard practice. They succeeded in suppressing it despite the fact that consumers, under a rate freeze, did not feel the passed-through benefits of lower energy costs.

New York had a concentrated set of high-cost utilities (the HHI was approximately 4000) whose stranded cost problems were significant due to the state's liberal treatment of PURPA facilities. They operated under uncertainties about stranded cost recovery that differed from California's. New York's settlement agreements did not include recovery provisions, which had

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<sup>105</sup> Two-Settlement & Market-based Regulation Frequently-Asked Questions (n.d.) at 4.

been left for future ratemakings. Its utilities, like California's, quickly learned the benefits of demand migration, and in conjunction with some customer interests (to whom energy prices were passed through) they were able to postpone the introduction of virtual bidding for two years. Unlike the other jurisdictions, New York provides a lengthy and detailed record of the various interests and the tactics they employed.

New England's ISO basically contained the same membership as NEPOOL, a highly heterogeneous mix of large and small, municipal and corporate utilities whose systems had widely differing resource mixes. They operated under six state regulatory agencies, some of which allowed retail competition. Stranded cost concerns, however, were minimal because the terms of "standard offers" made departure from utilities uneconomic for all but a handful of customers. The unit commitment procedures in New England were sufficiently unlike those in other jurisdictions that generators and utilities alike preferred the available indirect methods whose effects would be the same as those of virtual bidding, a point noted by the ISO's MMI. *De facto* virtual bidding had long existed in reality, and the redesigned market did little but change the techniques and the name.

PJM's attributes promised little difficulty for the introduction of virtual bidding simultaneously with the opening of its two-settlement market system. The region's utilities included high- and low-cost systems of widely varying sizes. Pennsylvania's had all reached stranded-cost settlements that gave them certainty of recovery regardless of the behavior of market prices or the volume of consumer departures under Pennsylvania's liberal retail choice program. Utilities had no more incentive to migrate demand than other market participants, virtual bids were introduced without controversy, and they have been an integral part of the market from its inception.

## **V. Summary and Conclusions**

After a century-long self-created spell of illusions about regulation, thirty years ago economists finally realized that intervention might be as much a market outcome as the activities it regulates. Government is a potentially powerful ally for any type of economic agent. Soon they discovered that utility regulators had interests that were often quite unrelated to economic efficiency. Interest groups might both set the agendas of regulators and influence their rulings in predictable ways. Some studies showed that those groups might even be responsible for the existence of regulatory bodies themselves.

For reasons still not clear, economists suspended much of their professional cynicism for the duration of electricity restructuring. Quite possibly this break with the past occurred because they were given a role in the design of the industry's new institutions such as they had never enjoyed in the past. In the process they interacted with the various interests, most often as paid consultants. For economists, restructuring provided the motivation for important and far-

reaching research. They extended their theories of markets and pricing to account for the special properties of electricity, and the even more unorthodox properties of its transmission. Instead of questioning how an Independent System Operator formed by politics could possibly independent, they generally stood back from the process that formulated the governance of the new institutions. It is possible that economists simply assumed that the world so valued competition and efficiency that the politics were a minor obstacle. Their valuable learning about collective decision-making and the behavior of nonprofit organizations was largely set aside.

I know of no work by economists at the inception of restructuring that attempted to analyze how a set of hitherto unseen institutions might function in reality. No prior deregulation had produced so drastic an institutional change as electricity's, putting some of its most critical assets under the control of collectively governed nonprofit organizations that were also charged with designing, operating, and monitoring the markets that deregulation would bring. Those who cast the governing votes would themselves be active representatives of politically knowledgeable interests, and the organization itself would be within the jurisdiction of a federal regulatory agency. The lack of professional interest is remarkable.

So is the timing. Electricity restructuring arrived in an era when economists had exhaustively examined the politics and performance of commissions. Some of those commissions had been formed to set rates and order policies in industries that were arguably natural monopolies. Research showing that these commissions often served the interests of monopoly and politics rather than efficiency and consumer welfare is a genuine professional achievement. The MMI is a regulatory agency, and like others an endogenous institution. Fortunately, its roots can be identified with some accuracy, as can the desires of the interests who determined its basic form. The comparison of how ISOs and their MMIs treated the unquestionably efficient institution of virtual bidding is certainly consistent with the economics of regulation, but is by no means a conclusive test.

Economists saw ISOs and MMIs as desirable, but after making that pronouncement they had little to say about the actual structures of the organizations. Now that they the organizations are here to stay, everyone might benefit from the insights that would result if economists put them back in their familiar world of agents seeking to advance their individual interests. Economists performed much useful research and their contributions, whether as consultants or scholars, have certainly improved the outcome of restructuring. They could probably have done much more by dropping a pose of institutional blindness and choosing instead to view MMIs through their admittedly jaundiced eyes.

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